Laurie (PSD permit.
File extension

File:
___ Enf/compliance
___ TV Application
___ TV Activity
✓ Other PSD

STATE OF WASHINGTON

DEPARTMENT OF ECOLOGY

P.O. Box 47600 • Olympia, Washington 98504-7600
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SEP 29 1999
OFFICE OF AIR

September 28, 1999

Mr. Ray Nye
Office of Air Quality
US EPA Region 10
1200 Sixth Avenue
Seattle, WA 98101

Dear Mr. Nye:

On September 27, 1999, the Department of Ecology's Air Quality Program (Washington Energy Siting Evaluation Council (EFSEC) has contracted Ecology's Air Quality Program to provide permitting services for this project) received a revised application for the second 18-month extension of the Satsop Combustion Turbine Project (Satsop) Prevention of Significant Deterioration (PSD) approval.

Ecology's Air Quality Program must determine if the revised application is complete within 30-days of receipt (by October 27, 1999). Please provide your comments to me no later than October 15, 1999.

Enclosed you will find copies of the Satsop PSD second revised extension application.

If you have any questions you can reach me at (360) 407-6811. Thank you.

Sincerely,

Alexander Piliaris

Alexander Piliaris, P.E.
Air Quality Program

AP:jr
Enclosure

Revised BACT Analysis for the Satsop Combustion Turbine Project

In Support of the 18-Month Permit Extension Request

Prepared For:

ENERGY NORTHWEST

DAMES & MOORE GROUP

Richland, Washington 99352 and Seattle, Washington 98121

Project No. 004004

September 23, 1999

Prepared By:

CASCADE ENVIRONMENTAL MANAGEMENT

316 SE Pioneer Way, Suite 294
Oak Harbor, Washington 98277

6.1 PSD PERMIT APPLICATION
(WAC 463-42-385)

Introduction

The Satsop Combustion Turbine (CT) Project to be located near Elma, Washington consists of two separate, combined-cycle natural gas fired power generation facilities rated at 245 Megawatts (MW) each. The major components of the project include two combustion turbine generators, two heat recovery steam generators, and two steam turbine generators. The proposed facility will use fuel oil solely as a backup fuel during periods of natural gas curtailment, not to exceed 360 hours per combustion turbine generator per calendar year.

In 1995, the Notice of Construction (NOC) and Prevention of Significant Deterioration (PSD) application was approved (No. EFSEC/95-01). If construction of the project does not commence within an eighteen-month period of final approval, then a new Best Available Control Technology (BACT) analysis must be performed to determine whether the proposed technologies remain as BACT and is to be included with a request to extend the PSD application. Construction did not commence within the first 18-month period and a revised BACT analysis was performed and submitted as part of permit extension application. The first NOC and PSD 18-month Extension Application (No. EFSEC/95-01 Extension-1) including a revised BACT analysis was approved on March 11, 1998.

The focus of this BACT analysis is to determine the existing and proposed control technologies associated with natural gas turbines, eliminate those technologies which are technologically infeasible or not proven in practice, and support the second renewal and extension of the PSD permit.

6.1.1 BACT "TOP-DOWN" ANALYSIS

Air emissions from the Satsop CT Project will include NO_x, SO_2, PM_{10}, CO, VOCs, and toxic air pollutants. The technologies available for controlling these emissions are discussed in this section. An updated "top-down" BACT analysis is presented to re-evaluate BACT for this project and its 18-month permit extension.

6.1.1.1 Methodology

The five steps of EPA's "top-down" BACT process consist of the following:

1. Identify all control technologies,
2. Eliminate technically infeasible options,
3. Rank remaining control technologies,
4. Evaluate the most effective control technology, and;
5. Select BACT.

A brief description of each step is presented below.

Step 1 - Identify All Control Technologies

The first step in a "top-down" BACT analysis is to identify all available control options. Air pollution controls include available technologies, methods, systems, and techniques for control of the regulated pollutant, as well as alternate production processes which may reduce the generation of pollutants. The control alternatives should not only include existing controls for the source category or piece of equipment in question, but also innovative technologies and controls applied to similar source categories.

Step 2 - Eliminate Technically Infeasible Options

In the second step of the "top-down" BACT evaluation, the technical feasibility of the control options identified in Step 1 are evaluated with respect to the source-specific factors. The list of technically infeasible control options must be clearly documented. The applicant must demonstrate that based on physical, chemical, and/or engineering principles, technical difficulties will preclude the successful use of the control option. Technically infeasible control options are then eliminated from further consideration in the BACT analysis.

Step 3 - Rank Remaining Control Technologies

In Step 3, all remaining control alternatives not eliminated in Step 2 are ranked in order of control effectiveness for the pollutants under review. The most effective control alternative is ranked at the top. A list of control alternatives is prepared for each pollutant and for each emission unit subject to the BACT analysis. The list presents the array of control technology alternatives and includes the following types of information:

- Range of control efficiencies (percentage of pollutant removed)
- Expected emission rate (tons per year, pounds per year)
- Expected removal efficiency at the Satsop CT Project (tons per year)
- Economic impacts (cost effectiveness)
- Environmental impacts (includes significant or unusual impacts on other media, water or solid waste)
- Energy impacts

A detailed analysis of costs and other impacts is not required if the applicant chooses the top or most stringent emissions control technology. The applicant must document that the control option is the most stringent alternative and briefly explain the environmental impacts.

Step 4 - Evaluate Most Effective Control Technology

After the available and technically feasible control technology options have been identified, potential impacts such as energy, environmental, and economic impacts are considered to determine the final level of control (Step 4). For each control option, the applicant must present an objective evaluation of each impact. Both beneficial and adverse impacts are described and, where possible, quantified. In general, BACT analyses focus on the direct impact of the control alternative.

In this analysis, the technology with the highest control efficiency is evaluated first. If this technology is found to have no adverse environmental, energy, or economic impacts, it is selected as BACT for this equipment or process and no further analysis is necessary. If the most stringent technology is shown to be inappropriate because of energy, environmental, or economic reasons, the applicant must fully document the rationale for this conclusion. Then, the next most effective control alternative on the list becomes the new control candidate and is similarly evaluated. This process continues until the technology under consideration cannot be eliminated due to potential source-specific reasoning.

Step 5 - Select BACT

The most effective control option not eliminated in Step 4 is proposed as BACT for the pollutant(s) and emission unit(s) under review.

6.1.1.2 RACT/BACT/LAER Clearinghouse Review

A review of EPA's RACT/BACT/LAER Clearinghouse (RBLC) database was conducted for the Satsop CT Project. The source type, natural gas turbines, was searched for all entries whose permits or latest updates were made after January 1, 1995. From the initial search results, the data set was further reduced by eliminating sources smaller than 90 MW and greater than 400 MW, and eliminating the sources whose allowable emissions were greater than the existing allowable emission rates for the Satsop CT Project. Table 6.1-13 presents a summary of permit determinations for power generation projects comparable to the Satsop CT Project, while Appendix A contains a complete listing of all facilities.

The RACT/BACT/LAER Clearinghouse review of the projects listed in Table 6.1-13 revealed that the control techniques for NO_x emissions less than 7 ppmv are SCR, and dry low-NO_x combustors (see Table 6.1-14). The most stringent of NO_x controls for this type of application (i.e., combustion turbine with HRSG and steam injection) is steam injection with SCR. As discussed below, the RACT/BACT/LAER Clearinghouse review is the basis for selecting BACT for the proposed facility.

The following "top-down" BACT analysis was performed for natural gas, the primary fuel for the combustion turbines. Since fuel oil will only be used in an emergency situation and the use of fuel oil will be limited to 15 days (360 hours) per year, a "top-down" BACT analysis was not conducted for fuel-oil firing of the combustion turbines. BACT for firing with fuel oil was selected based on the BACT listings for fuel oil firing presented in the RACT/BACT/LAER Clearinghouse.

TABLE 6.1-13
RACT/BACT/LAER SEARCH RESULTS FOR RECENT POWER GENERATION PROJECTS

Facility Name	Location	EPA Region	Permit Date Or Last Update	Size (each turbine)
Alabama Power Company- Theodore Cogeneration	Theodore, AL	4	4/20/99	170MW
Berkshire Power Development	Agawam, MA	1	4/19/99	1792 MMBTU
Brooklyn Navy Yard Cogeneration Partners	NYC, New York	2	6/30/95	240 MW
Carolina Power & Light	Hartsville, SC	4	4/29/96	1520 MMBTU
Carolina Power & Light	Goldsboro, NC	4	8/19/96	1907.6 MMBTU
Casco Ray Energy Company	Veazie, ME	1	4/19/99	170 MW
Chehalis Generating Facility	Chehalis, WA	10	6/97	230 MW

TABLE 6.1-13 (CONTINUED)
RACT/BACT/LAER SEARCH RESULTS FOR RECENT POWER GENERATION PROJECTS

Facility Name	Location	EPA Region	Permit Date Or Last Update	Size (each turbine)
Hermiston Generating Company	Hermiston, Oregon	10	1/27/99	1696 MMBTU
LSP-Cottage Grove LP	Cottage Grove, PA	5	4/19/99	1988 MMBTU
Millennium Power Partners, LP	Charlton, MA	1	4/19/99	2534 MMBTU
Mobile Energy, LLC	Mobile, AL	4	4/09/99	168 MW
Newark Bay Cogeneration Partnerships, LP	Newark, NJ	2	5/29/95	136 MW
Pilgrim Energy Center	Islip, NY	2	4/27/95	1400 MMBTU
Portland General Electric Company	Boardman, Oregon	10	8/6/97	1720 MMBTU
Sacramento Power Authority - Campbell Soup	Sacramento, CA	9	4/13/99	1257 MMBTU
Sithe/Independence Power Partners	Oswego, New York	2	9/13/94	2133 MMBTU

TABLE 6.1-14
RBLC SEARCH RESULTS FOR NO_x

Facility[a]	Size (each turbine)	Fuel	Allowable NO_x Emissions	Type of Control
Alabama Power Company- Theodore Cogeneration	2534 MMBTU	Natural Gas	0.013 lb/MMBTU	SCR w/Dry Low NOx
Berkshire Power Development	168 MW	Natural Gas	20.3 lb/hr	SCR w/Dry Low NOx

TABLE 6.1-14 (CONTINUED)
RBLC SEARCH RESULTS FOR NO_x

Facility[(a)]	Size (each turbine)	Fuel	Allowable NO_x Emissions	Type of Control
Blue Mountain Power, LP	1400 MMBTU	Natural Gas Fuel Oil	4.0 PPMV @ 15% O_2	SCR w/Dry Low NOx (LAER) Steam injection
Brooklyn Navy Yard Cogeneration Partners	240 MW	Natural Gas	3.5 PPMV @ 15% O_2	SCR (LAER)
Casco Ray Energy Company	170 MW	Natural Gas	3.5 PPMV @ 15% O_2	SCR
Chehalis Generating Facility	230 MW	Natural Gas	4.5 PPMV @ 15% O_2 (Proposed as new BACT)	SCR
Hermiston Generating Company	1696 MMBTU	Natural Gas	4.5 PPMV @ 15% O_2	SCR
LSP-Cottage Grove LP	1988 MMBTU	Natural Gas	4.5 PPMV @ 15% O_2	SCR
Millennium Power Partners, LP	2534 MMBTU	Natural Gas	0.013 lb/ MMBTU	SCR
Mobile Energy, LLC	168 MW	Natural Gas	0.019 lb/MMBTU	SCR w/Dry Low NOx
Pilgrim Energy Center	1400 MMBTU	Natural Gas Fuel Oil	4.5 PPMV @ 15% O_2	SCR Steam Injection
Portland General Electric Company	1720 MMBTU/hr	Natural Gas	4.5 PPMV @ 15% O_2	SCR
Sacramento Power Authority- Campbell Soup	1257 MMBTU	Natural Gas	3.0 PPMV @ 15% O_2	SCR w/Dry Low NOx
Sithe/Independence Power Partners	2133 MMBTU/hr	Natural Gas	4.5 PPMV @ 15% O_2	SCR w/Dry Low NOx

(a) See Table 1 for locations.
(b) SCR = Selective Catalytic Reduction.

Other Facilities Not Found in the RBLC

Other facilities have been permitted and/or built in Washington State that are not part of the RBLC; typically because these facilities utilized non-BACT rationales in selecting their control technology. Each of these facilities utilized a PSD-avoidance and/or modeling constraint strategy to determine their emission rates. At the time of their application preparation, each of these facilities were influenced by or located within a nonattainment region and would have needed offsets in order to permit 100 tons or more of any nonattainment pollutant or precursor. Consequently, these facilities have had no impact upon any BACT analyses, to date. Now, however, two of these facilities have proceeded to the stages where consideration of their permit limits is warranted. The Clark County PUD facility is built and operating within their permit limits. And one Everett, WA facility is in the process of construction. Table 6.1-14a presents the pertinent information on these facilities.

TABLE 6.1-14a
OTHER FACIILTIES IN WASHINGTON STATE

Facility	Size (each turbine)	Fuel	Allowable NO_x Emissions	Type of Control	Permit Date	Status
Tenaska, Frederickson	248 MW	Natural Gas No. 2 Oil	3 ppm @ 15% O2 8 ppm @ 15% O2	LAER for PSD Avoidance Duct Burner and SCR	1995	Expired Permit
Northwest Power Company, Everett	235 MW	Natural Gas No. 2 Oil	3.5 ppm @ 15% O2 3.5 ppm @ 15% O2 (8-hour average)	LAER for PSD Avoidance SCR	1997	Construction
Northwest Power Company - Delta II, Everett	247.4 MW	Natural Gas No. 2 Oil	3.5 ppm @ 15% O2 42 ppm @ 15% O2 (8-hour average)	PSD Avoidance SCR	1999	Permit Only
Clark Public Utilities, Vancouver	248 MW	Natural Gas No. 2 Oil	4 ppm @ 15% O2 9 ppm @ 15% O2 (24-hour average)	LAER for PSD Offset Avoidance Dry Low-Nox and SCR	1995	Operational

6.1.1.3 Nitrogen Oxides

The formation of nitrogen oxides is the result of thermal oxidation of diatomic nitrogen in the combustion chamber air. The rate of formation is dependent upon combustion temperature, residence time of combustion products at high temperatures, and the availability of oxygen in the flame zone of a combustion turbine generator. This section addresses the available control alternatives for NO_x emissions.

Available Control Technologies

Control technologies for NO_x emissions can be classified as combustion modifications or post-combustion controls. The available NO_x control technologies for gas combustion turbines are briefly described below.

Combustion Modifications

Steam/Water Injection: Steam/water injection is a widely used gas turbine NO_x emission control. The steam or water is injected into the combustion zone to lower the combustion zone temperature. Steam/water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to (1) vaporize the water (latent heat of vaporization), and (2) raise the vaporized water temperature to the combustion temperature. High-purity water must be used to prevent turbine corrosion and deposition of solids on the turbine blades. Steam injection employs the same mechanisms to reduce the peak flame temperature with the exclusion of heat absorbed due to vaporization, since the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO_x reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 pounds of water and 0.5 to 2.0 pounds of steam per pound of fuel. Water/steam injection will not reduce the formation of fuel NO_x. The maximum amount of water/steam that can be injected depends on the CT combustor design. Excessive rates of water/steam injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of wet injection to reduce NO_x emissions also depends on turbine combustor design. For a given turbine design, the maximum water/fuel ratio (and maximum NO_x reduction) will occur up to the point where cold-spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine.

Dry Low-NO_x Combustor: The modern dry low-NO_x combustor is a three-staged, lean, premixed design, which utilizes a central diffusion flame for stabilization. The lean premixed approach burns a lean fuel-to-air mixture for a lower combustion flame temperature resulting in lower NO_x. The combustor operates with one of the lean premixed stages and the diffusion pilot at lower loads and all three stages at higher loads. This provides efficient combustion at lower temperatures throughout the combustor loading regime. The dry low-NO_x combustor reduces NO_x emissions by up to approximately 87 percent over a conventional combustor.

Catalytica/XONON Flameless Combustion System: Catalytica Combustion Systems has developed a new technology where a catalyst limits the temperature in the combustor below the temperature where NOx is created. This controlled reaction in the XONON combustor results in the gas turbine operating with ultra-low emissions. The technology proposes that emissions rates can achieve approximately 3 ppm NOx with CO and hydrocarbons less than 10 ppm. According to Catalytica these results have been proven in practice using a Kawasaki turbine at a test facility in Tulsa, Oklahoma. However, this test facility is not similar in size to the proposed Satsop project. The XONON technology has been installed at Silicon Valley Power in Santa Clara, California using a larger turbine where initial compliance test results have shown NOx emissions at levels less than 3 ppm. As more information on installations with the turbine size of the Satsop CT Project become available, this technology may require additional consideration. Meanwhile, the Bay Area Air Quality Management District's (BAAQMD) BACT guidance stipulates an emission rate of 5 ppm as BACT. Appendix B contains a table detailing the BAAQMD BACT guidance for natural gas combustion turbines greater than or equal to 23 mmBtu/hr heat input.

Post-Combustion Controls

Selective Catalytic Reduction: In the SCR process, a reducing agent, such as aqueous ammonia, is introduced into the turbine's exhaust upstream of a metal or ceramic catalyst. As the ammonia/exhaust gas mixture passes through the catalyst bed, the ammonia selectively reduces the nitrogen oxide compounds present in the exhaust to produce elemental nitrogen (N_2) and water (H_2O). Ammonia (NH_3) is the most commonly used reducing agent. Adequate mixing of NH_3 in the exhaust gas and control of the amount of NH_3 injected (based on the inlet NO_x concentration) are critical to obtaining the required reduction. For the SCR system to operate properly, the exhaust gas must maintain minimum O_2 concentration and remain within a specified temperature range (typically between 580 and 650 degrees F), with the range dictated by the types of catalyst. Exhaust gas temperatures greater than the upper limit (850 degrees F) will pass the NO_x and unreacted ammonia through the catalyst. The most widely used catalysts are vanadium, platinum, titanium, or zeolite compounds impregnated on metallic or ceramic substrates in a plate of honeycomb configuration. The catalyst life expectancy is typically 3 to 6 years, at which time the vendor can recycle the catalyst to minimize waste.

The SCR catalyst is subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical "poisoning". Principal poisons include arsenic, sulfur, potassium, sodium, and calcium.

One concern when using the SCR catalyst on fuels containing sulfur is the oxidation of flue gas SO_2 to SO_3 which will then combine with H_2O vapor to form H_2SO_4. Accordingly, corrosion of downstream piping and heat transfer equipment (which will operate at temperatures below the H_2SO_4 dew point) will be of concern when using SCR with sulfur-bearing fuels. Also, SO_3 will combine with unreacted NH_3 to form ammonium bisulfate and ammonium sulfate. Ammonium bisulfate is a hyposcopic solid at approximately 300 degrees F and can deposit on equipment surfaces below this temperature as a white solid. Both ammonium bisulfate and ammonium sulfate will be expected to deposit on HRSG heat transfer equipment when temperatures below 300 degrees F occur. Since ammonium bisulfate is hyposcopic, the material will absorb H_2O, forming a sticky substance which can cause fouling of heat transfer equipment. Ammonium bisulfate cannot be easily removed due to its sticky nature; a unit shutdown will be required to clean fouled equipment. Formation of ammonium salts could also result in a significant increase in particulate emissions when operating an oil fuel. Problems associated with ammonium salt deposition can be ameliorated, to some extent, by reducing the NH_3/NO_x molar ratio when firing sulfur-containing fuels.

Selective Non-Catalytic Reduction (SNR): Similar to the SCR process, SNR uses ammonia or a urea-based reagent to chemically react with the NO_x in the exhaust gas stream forming diatomic nitrogen and steam. Because no catalyst is used for SNR, the temperature required for the reaction ranges from 1,600 to 1,750E F for ammonia, and from 1,000 to 1,900E F for urea-based reagents. The NO_x conversion efficiency declines below these temperature ranges and the concentration of unreacted reagent in the emissions ("slip") increases. Above these temperatures the reagent will tend to react with the excess oxygen in the exhaust gas instead of the NO_x forming additional NO. At optimum temperatures, NO_x destruction efficiencies range from 75 percent to over 90 percent.

This control technology, originally developed by Exxon Engineering, is available from several companies and is currently in commercial operation at several plants in Japan.

Evaluation of Technical Feasibility

The following section addresses the technical feasibility of the NO_x control technologies described above with respect to the Satsop CT Project.

<u>Combustion Modifications</u>

Steam/Water Injection: This technology is capable of reducing exhaust gas NO_x concentrations from natural gas firing to a concentration of 25 ppmvd, assuming combustion is at 15 percent oxygen. This reduction will not satisfy regulatory requirements without a post-combustion control. This technology could be implemented on the Satsop CT Project and is evaluated below.

Dry Low-NO_x Combustor: Dry low-NO_x combustors will be an integral part of the CTGs designed for the Satsop CT Project. This technology is guaranteed by the manufacturer to reduce NO_x emissions from the CTGs to 25 ppmvd for natural gas firing. This reduction will not satisfy current regulatory requirements without a post-combustion control. This technology is evaluated below.

XONON Flameless Combustion System: Catalytica has been conducting field tests to verify the emission performance of the XONON technology. However, the current field tests are being run using a 1.5 MW engine and is the first use of the XONON technology on a full-scale engine emitting less than 3.0 ppm NOx and CO under 10 ppm. Because this innovative technology has not been proven on a turbine within an equivalent size range as that proposed for the Satsop CT Project, this technology is deemed technologically infeasible, until further results show the application is successful on larger engines.

Post-Combustion Controls

Selective Catalytic Reduction: This technology is readily available for many applications, including combustion turbines. Typically, SCR is an integral element of the HRSG unit on combined cycle plants, where the exhaust gas is at the optimum temperature. This technology is evaluated below.

Selective Non-Catalytic Reduction: SNR is also readily available for many applications, including combustion turbines. However, the exhaust gas temperature from the Satsop CT Project is not hot enough to achieve the highest possible efficiency from this technology. Raising the temperature of the CTG exhaust without using duct burners is not feasible. If SNR were to be installed as NO_x control, the removal efficiency will be lower than normal (70 to 75 percent) due to temperature constraints. This technology is ranked below using the lower removal efficiency (70 to 75 percent).

Control Technology Hierarchy

As noted above, NO_x controls include combustion modifications, post-combustion controls, or combination of these controls. Within each category, control technologies are ranked according to their pollutant removal efficiencies, with a higher ranking given to control methods with higher removal efficiencies.

The dry low-NO_x combustors and steam/water injection methods are the only technically feasible combustion modification options for the CTGs at the Satsop CT Project. Only SCR is considered technically feasible as a post-combustion control for this project.

Combining the combustion modifications with the post-combustion modifications has the potential to yield even higher overall NO_x removal efficiencies. Westinghouse has determined that 3 ppmvd NO_x emissions can now be achieved using SCR in conjunction with dry low-NO_x combustors. The combination of dry low-NO_x combustors with the SCR ranks as the most efficient combination of control technologies. The combination of steam/water injection and SCR is ranked the second most effective control technology.

The technology ranking from highest (most effective) to lowest for the Satsop CT Project is as follows:

1. Dry low-NO_x combustors with SCR
2. Water/steam injection with SCR
3. Dry low-NO_x combustors
4. Water/steam injection
5. Conventional combustors with SCR
6. Conventional combustors with SNR.

Table 6.1-15 provides a comparison of control efficiencies for these technologies.

TABLE 6.1-15
EMISSION CONTROL EFFICIENCIES FOR BACT ANALYSIS

Emission Control Mechanism	CT Load	Temperature (F)	NO_x Emission Concentration (ppmvd @15% 0_2 and ISO)	NO_x Emission Rate (lb/hr)	Control Efficiency (Ratio to No Control)
NATURAL GAS FUEL					
Conventional Combustor	Base	5	190	1287	--
Dry Low NO_x (DLN) Combustor	Base	5	25	169.3	86.8%
DLN w/SCR	Base	5	3	20.3	98.4%
NO. 2 DISTILLATE FUEL					
Emission Control Mechanism	**CT Load**	**Temperature (F)**	**NO_x Emission Concentration (ppmvd @15% 02 and ISO)**	**NO_x Emission Rate (lb/hr)**	**Control Efficiency (Ratio to No Control)**
Conventional Combustor, no water injection	Base	5	360	2,723	--
Dry Low NO_x Combustor, no water injection	Base	5	225	1,702	37.5%
Dry Low NO_x Combustor, water injection	Base	5	65	491.7	81.9%
DLN w/SCR, water injection	Base	5	12	90.8	96.6%

BACT Analysis

The environmental, energy, and economic impacts of the above-ranked NO_x control technologies for the Satsop CT Project are presented in this section. The highest ranked NO_x control is a combination of the dry low-NO_x combustor and SCR with a new emission limit of 3.5 ppm. The economic impacts are not revised from the original BACT demonstration.

Dry Low-NO_x Combustors

Environmental Impacts: Dry low-NO_x combustors pose no environmental impacts when implemented on a Westinghouse 501F combustion turbine. The emission reduction is the same as with steam injection, but without increasing CO emissions and water consumption.

Energy Impacts: There is no energy impact associated with dry low-NO_x combustors when firing natural gas. The power output for a gas turbine using conventional combustors is the same as the output for a turbine with dry low-NO_x combustors.

Economic Impacts: The cost estimate for using dry low-NO_x combustors is not presented with the SCR economic because the dry low-NO_x combustors are an integral part of the 501F combustion turbine.

SCR

Environmental Impacts: There are several environmental concerns associated with SCR control technology. The primary concern is that NH_3 emissions are created when ammonia passes through the catalyst unreacted and is exhausted through the stack. Most SCR manufacturers guarantee very small amounts of ammonia slip (less than 10 ppm). However, ammonia slip can increase significantly during start-ups, upsets/failures of the NH_3 injection system, or due to catalyst degradation. In instances where such events have occurred, NH_3 exhaust concentrations of 50 parts per million by volume (ppmv), or greater, have been measured.

NH_3 is most frequently shipped by highway or rail and the potential exists for a spill due to an accident, although the likelihood is low. Spills may occur during the transfer of the aqueous ammonia from one container or vessel to another. In addition, the SCR catalyst has the negative side effect of forming SO_3 from some of the SO_2 entering the system in the exhaust stream. SO_3 reacts with the unreacted ammonia in the exhaust stream to produce ammonium sulfate and ammonium bisulfate salts. As these sticky particles buildup on the HRSG boiler tubes, they diminish the heat transfer qualities of the HRSG turbine which reduces the efficiency of the plant. Also, these salt particles create corrosion problems within the HRSG. As a result, the use of an SCR requires additional HRSG maintenance in addition to increasing emissions of particulate matter.

Energy Impacts: The greater the catalyst volume the higher the pressure drop. The presence of the SCR system in the HRSG introduces added resistance to the turbine exhaust, which increases the combustion turbine back pressure. This results in more energy being expended to force air through the turbine, thus reducing the turbine power output. According to the "Alternative Control Techniques Document--NO_x Emissions from Stationary Gas Turbines" (EPA 1993c), the backpressure from SCR reduces turbine output by approximately 0.5 percent of the turbines design output, or 1.135 MW at each turbine for the Satsop CT facility. This performance loss is approximately $800,856 per year per CT unit.

Economic Impacts: An assessment of economic impacts was performed for the baseline installation of a dry low-NO_x combustor with SCR technology as the post-combustion control. The baseline technology dry-low-NO_x turbine is expected to achieve NO_x concentrations of 25 ppmvd (maximum) for natural gas operation, and the SCR is assumed to achieve NO_x concentrations of 3 and 12 ppmvd at 15 percent O_2 for gas and oil operation, respectively. SCR control costs used in the economic analysis were based on the reduction of NO_x concentrations from 25 to 3 ppmvd at 15 percent O_2 for natural gas operation.

The cost impact analysis was conducted using the Office of Air Quality Planning Standards factors (OAQPS, Chapters 2 and 9, revised). Additional cost factors were obtained from the "Alternative Techniques Document--NO_x Emissions from Stationary Gas Turbines" (EPA 1993c). The cost factors for the primary fuel, natural gas, are summarized in Table 6.1-16 and calculations are provided in Table 6.1-17. The dollar values are from 1994 data. Emissions reductions were calculated based on the use of natural gas for 8400 hours per year.

Cost effectiveness for the application of SCR technology to the Satsop CT Project was determined to be $4,762 per ton of NO_x removed per CT unit.

TABLE 6.1-16
SCR ECONOMIC COST FACTORS[a]
(PER UNIT)

Factor	Units	Value
Hours Burning Natural Gas	hours	8400
Turbine Output	MW	227
Interest Rate	percent	7
Control System Life	years	15
Control System Life Capital Recovery Factor	-	0.1089
Catalyst Life	years	5
Catalyst Capital Recovery Factor	-	0.2439
Catalyst Disposal Cost	$/cu. ft.	21
Catalyst Volume	cu. ft.	16,902
Ammonia Cost	From Vendor	$139,783
Electricity Cost	$/kwh	0.084
System Downtime SCR maintenance, inspections, cleaning	hours/year	760
Labor Cost Operator/Maintenance	$/hour	36.02/43.9

(a) Based on natural gas fuel operation.
(b) Interest rate from EPA's OAQPS Cost Control Manual, 5th Edition (1996).

TABLE 6.1-17
PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS
FOR SCR CONTROL OF NO_X EMISSIONS FROM COMBUSTION TURBINES[a]

Cost Type	Calculation[b]	Cost ($)
Direct Costs		
Purchased Equipment Cost		
Basic Equipment Cost = A	A	$2,200,000
Instrumentation	0.10 x A	$220,000
Sales Tax	0.03 x A	$66,000
Freight	0.05 x A	$110,000
Catalyst Cost	Provided	$1,700,000
Total Purchased Equipment Cost = B	B	$4,296,000
Direct Installation Cost		
Foundation and Support	0.12 x B	$515,520
Handling and Erection	0.40 x B	$1,718,400
Electrical	0.01 x B	$42,960
Piping	0.03 x B	$1,288,800
Insulation	0.01 x B	$42,960
Painting	0.01 x B	$42,960
Total Direct Installation Cost	0.85 x B	$3,651,600
Indirect Cost (Installation)		
Engineering	0.10 x B	$429,600
Construction and Field Expenses	0.10 x B	$429,600
Contractor Fees	0.10 x B	$429,600
Start-up	0.01 x B	$42,960
Performance Test	0.01 x B	$42,960
Contingencies	0.03 x B	$128,880
Total Indirect Costs	0.35 x B	$1,503,600
Cost Type	**Calculation[b]**	**Cost ($)**
Total Capital Costs = C	C	**$9,451,200**
Total Annualized Capital Investment		**$561,401**

TABLE 6.1-17 (CONTINUED)
PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS FOR SCR CONTROL OF NO_X EMISSIONS FROM COMBUSTION TURBINES[a]

Cost Type	Calculation[b]	Cost ($)
Direct annual costs, $/yr		
Operating labor	(0.5 hr/8 hr-shift) x ($36.02/hr) x (H)	$18,911
Supervisory labor	(0.15) x (operating labor)	$2,837
Maintenance labor and materials	2 x (0.5 hr/8-hr shift x H x $43.90/hr)	$46,095
Catalyst replacement	Provided by Vendor	$399,330
Catalyst disposal	(V) x ($21/ft^3) x (.2439)	$86,570
Anhydrous ammonia	Provided by Vendor, Annualized	$139,783
Dilution steam	(N) x (0.95/0.05) x (MW H_2O/MW NH_3) x ($8.45/1,000 lb steam) x (2,000 lb/ton)	$73,267
Electricity (performance loss)[c]	(0.005) x (TMW) x ($0.084/KWH) x (1,000 KW/MW) x (H)	$800,856
Total direct annual costs		$1,567,649
Indirect annual costs, $/yr		
Overhead	(0.6) x (all labor and maintenance material costs)	$40,705
Property taxes, insurance, and administration	(0.04) x (total capital investment)	$378,048
Capital recovery	(0.1098) x [total capital investment - (catalyst replacement/0.2439]	$993,895
Total Indirect annual costs, $/yr		$1,412,649
Total Annual Cost		**$2,980,297**
Pollutant Controlled (tons/yr)		**625.8**
Cost Effectiveness, ($/ton)		**$4,762**

(a) Data for Direct Annual Costs are from Alternative Control Techniques Document--NO_x Emissions from Stationary Gas Turbine (EPA 1993c).
(b) Cost factors are from EPA OAQPS Cost Control Manual, 5th Edition (1996).
(c) TMW = Total megawatts

Table 6.1-18 provides removal efficiencies for SCR NO_x removal.

TABLE 6.1-18
SCR NO_x REMOVAL EFFICIENCY
(Per Unit)

Option	DLN Combustor	DLN + SCR
Natural Gas Fired		
NO_x ppmvd @ 15% O_2	25	3
NO_x emitted (lb/hr)	169.3	20.3
NO_x removed (lb/hr)	Base	149
NO_x removed (tons/yr)	Base	625.8
Fuel Oil Fired		
NO_x ppmvd @ 15% O_2	65	12
NO_x emitted (lb/hr)	491.8	90.8
NO_x removed (lb/hr)	Base	401
NO_x removed (tons/yr)	Base	72.2

Selected BACT

Although there can be adverse effects using SCR control technology, previous BACT determinations in Washington State indicate that SCR is required to reduce NO_x emissions down to levels of 7 ppmvd or lower. Tables 6.1-14 and 6.1-14a show emission levels for natural gas range from 3 to 4.5 ppmvd. The Satsop CT Project is located in an attainment area for ozone, and the implementation of this technology should not significantly contribute to O_3 levels. Using a combination of the most advanced dry low-NO_x combustor technology with SCR control technology provides a significant amount of NO_x reduction to a level of 3 ppmvd at 15 percent O_2. The NO_x emission limits are shown in Table 6.1-19 and Table 19a.

The RACT/BACT/LAER Clearinghouse search identified water steam injection as BACT during fuel oil firing in addition to SCR for this turbine type. Water injection with SCR is proposed as BACT during fuel oil firing. The water injection/SCR system will be designed to operate during fuel oil firing to prevent the fuel oil from poisoning the catalyst.

TABLE 6.1.19
PROPOSED BACT NO_X EMISSION LIMITS FOR EACH CT UNIT[a]

Pollutant	Natural Gas			Distillate Fuel Oil[b]		
	(ppmvd) at 15% O_2	(lb/million BTU)[c]	(lb/hr)	(ppmvd) at 15% O_2	(lb/million BTU)[c]	(lb/hr)
NO_x	3	0.017	20.3	12	0.0472	90.8

[a] Based on 100 percent CT load.
[b] Distillate fuel oil limits are based on fuel bound nitrogen content less than or equal to 0.015 weight percent.
[c] lb/million BTU based on fuel higher heating value.

TABLE 6.1-19a
PROPOSED BACT NO_X EMISSION LIMITS FOR TWO CT UNITS[a]

Pollutant	Natural Gas			Distillate Fuel Oil[b]		
	(ppmvd) at 15% O_2	(lb/million BTU)[c]	(lb/hr)	(ppmvd) at 15% O_2	(lb/million BTU)[c]	(lb/hr)
NO_x	3	0.017	40.6	12	0.0472	181.6

[a] Based on 100 percent CT load.
[b] Distillate fuel oil limits are based on fuel bound nitrogen content less than or equal to 0.015 weight percent.
[c] lb/million BTU based on fuel higher heating value.

6.1.1.4 Sulfur Dioxide

SO_2 emissions from gas turbines are a function of the sulfur content of the fuel, with virtually all fuel sulfur converted to SO_2. Coal generally has the highest sulfur content, followed by crude oils, sewage gas, waste fuels, and refined fuel oils (including No. 2). Natural gas has only trace amounts of sulfur. This section describes available control equipment and the BACT analysis for sulfur dioxide.

Available Control Technologies

The RACT/BACT/LAER Clearinghouse search completed for SO_2 is summarized in Table 6.1-20 for all facilities conforming to the search data criteria for SO_2 controls when using either natural gas or low-sulfur fuel oil after 1992 whose emissions were equivalent or less than those proposed for the facility and allowed in the PSD permit. Other technically feasible control technologies are two typical flue gas desulfurization processes: wet and dry scrubbing. These control technologies are described below.

TABLE 6.1-20
RBLC SEARCH RESULTS FOR SO_2

Facility[a]	Size (each turbine)	Fuel	Allowable SO_2 Emissions	Type of Control
Carolina Power & Light	1907 MMBTU/hr	No. 2 fuel oil Natural Gas	308.5 lb/hr 1.0 lb/hr	Low-sulfur oil (0.15%) Combustion Controls
Chehalis Generating Facility	230 MW	Fuel Oil	10.4 lb/hr	Low-sulfur oil (0.05%)
Millennium Power Partners, LP	2534 MMBTU/hr	Natural gas	0.0023 lb/MMBTU	Fuel Specifications
Sithe/Independence Power Partners	2133 MMBTU/hr	Natural Gas	Not listed	Use of Natural Gas

[a] See Table 6.1-13 for locations.

Wet Scrubbing

In this process, the exhaust gas is passed through a spray tower scrubber. These devices work on the principle of reacting a liquid-phase reagent with the SO_2 in the exhaust stream to form various end products (depending on the type of reagent used). Optimum process temperatures are approximately 100 to 140 degrees F. Thus, some type of gas cooling is usually required upstream of the spray tower scrubber. Since some of the slurry is entrained by the gas as small droplets, the exhaust stream leaving the scrubber is normally passed through a mist eliminator to remove the droplets and return them to the scrubber. The exhaust gas is then directed to a stack.

Limestone is the most frequently used reagent in wet scrubbing systems since the cost is much less than that of either lime or sodium carbonate. Wet scrubbing devices are predominately used in coal-fired boiler facilities as well as some chemical plants and kraft pulp mills.

Dry Scrubbing

A dry scrubber removes SO_2 by mixing the flue gas with an atomized slurry in a spray dry scrubber. The water in the slurry evaporates, and the SO_2 is subsequently absorbed by the remaining fine solids. Reaction temperatures are maintained slightly above the gas dew point by controlling the amount of water in the slurry. The cleaned gases are then routed to the exhaust stack or particulate capturing/collection device.

This technology is mainly used in large coal-fired utility boilers. The reagent used in these systems is usually lime since it is more readily available and cheaper than sodium carbonate.

Use of Low-Sulfur Fuel

The use of low-sulfur fuel is widely used and accepted as a viable SO_2 emissions control for combined cycle facilities nationwide. Low-sulfur fuels include fuel oils with limited fuel content. Reviewing the

RACT/BACT/LAER Clearinghouse shows that low-sulfur fuel oils have sulfur contents ranging from less than 0.3 to less than 0.05 percent by weight. Natural gas is considered a clean fuel containing only trace amounts of sulfur. The national average for sulfur content in natural gas is 0.2 grains per 100 cubic feet of gas. Natural gas is the primary fuel for this project. On-road specification No. 2 distillate fuel oil (diesel) is the back-up fuel that will be used only if natural gas is unavailable, and will not be used more than 15 days (360 hours) per year.

Evaluation of Technical Feasibility

Wet Scrubbing

Wet scrubbing is widely used in large coal-fired boilers, kraft pulp mill, and other large chemical processing plants. However, it has never been implemented on a combustion gas turbine facility. Most combustion turbine facilities are small and the pressure drops imposed by wet scrubbing applications would be a severe operational constraint. Wet scrubbing is considered technically infeasible for CTGs because an induced draft fan or similar device would be required to overcome the pressure drop in the exhaust system. This may cause CTG operation problems with a fan drawing exhaust gas from the turbine and with the air/fuel ratio controls in the combustor. There is no commercial experience with exhaust gas blowers in CTG equipment trains. This technology was not evaluated further in the BACT analysis.

Dry Scrubbing

Dry scrubbing is also primarily used with large utility coal-fired boilers and has never been implemented on a CTG. As with wet scrubbing, this technology would impose excessive pressure drop constraints on a combustion turbine facility. Thus, this technology was considered technically infeasible for the same reason as presented for wet scrubbers and was not evaluated any further in this BACT analysis.

Use of Low-Sulfur Fuel

Low-sulfur fuel is commonly used with combustion gas turbine facilities throughout the United States to control SO_2 emissions, and is considered technically feasible. This is the only known SO_2 control to be used with combustion gas turbines.

Control Technology Hierarchy

The only SO_2 control remaining in this BACT analysis, and the only one known to be implemented on combustion gas turbines, is use of low-sulfur fuels.

Selected BACT

Table 6.1-20 shows SO_2 emission limits that are presented in the RACT/BACT/LAER Clearinghouse, when using natural gas fuel and limiting the sulfur content of distillate fuel oil to 0.05 percent. The Satsop CT Project SO_2 emission limits, which are representative of the permitted limits shown in the RACT/BACT/LAER Clearinghouse, are shown in Table 6.1-21. Therefore, using natural gas and limiting the sulfur content of back-up fuel oil to 0.05 percent is considered BACT for controlling SO_2 emissions.

TABLE 6.1-21
PROPOSED BACT SO_2 EMISSION LIMITS FOR TWO CT UNITS[(a), (b)]

Pollutant	Natural Gas			Distillate Fuel Oil[(c)]		
	(ppmvd)	(lb/million BTU)[(d)]	(lb/hr)	(ppmvd)	(lb/million BTU)[(b)]	(lb/hr)
SO_2	1	0.0011	4	13	0.052	202

(a) Based on 100 percent CT load.
(b) Data for emissions and stack exit parameters provided by Westinghouse.
(c) Distillate fuel oil sulfur content is 0.05 percent by weight.
(d) lb/million BTU based on fuel higher heating value.

6.1.1.5 Carbon Monoxide and Volatile Organic Compounds

CO is a product of incomplete combustion, where oxygen is present in insufficient quantities to fully oxidize the fuel. In addition, CO emission levels are a direct function of the air-to-fuel ratio. Combustion inefficiencies introduced by combustion modifications for NO_x control increase the generation of CO. VOC emissions are also products of incomplete combustion. Some VOCs are involved in the process of ozone formation.

Available Control Technologies

Control technologies for CO and VOC can be classified as combustion modifications or post-combustion controls. Tables 6.1-22 and 6.1-23 list the control technologies available for the control of CO and VOC, respectively. This section describes each technology and its technical feasibility for controlling the organic contaminant emissions from a combustion gas turbine.

TABLE 6.1-22
RACT/BACT/LAER SEARCH RESULTS FOR CO

Facility[a]	Size (each turbine)	Fuel	Allowable CO Emissions	Type of Control
Brooklyn Navy Yard Cogeneration Partners, LP	240 MW	Natural gas	4 PPM @ 15% O2	LAER, Unknown
Chehalis Generating Facility	Chehalis, WA	Natural Gas	3.0 PPM @ 15% O2	Catalytic Oxidation
Hermiston Generating Co.	1696 MMBTU/hr	Natural gas	15 PPM @ 15% O2	Combustion controls
Newark Bay Cogeneration Partnerships, LP	617 MMBTU	Natural gas	1.8 PPM @ 15% O2	Catalytic Oxidation (LAER)
Northwest Regional Power Facility			3.0 PPM @ 15% O2	Catalytic Oxidation
PGE - Boardman Facility	1720 MMBTU/hr	Natural gas	15 PPM @ 15% O2	Combustion controls
Sithe/Independence Power Partners	2133 MMBTU/hr	Natural gas	13 PPM @ 15% O2	Combustion controls

[a] See Table 6.1-13 for locations

TABLE 6.1-23
RACT/BACT/LAER SEARCH RESULTS FOR VOCs

Facility[a]	Size (each turbine)	Fuel	Allowable VOC Emissions	Type of Control
Auburndale Power Partners, LP	1214 MMBTU/hr	Natural gas	6 lb/hr (10 lb/hr oil)	Fuel specifications Combustion control
Blue Mountain Power Company	153 MW	Natural gas	4 PPM	Fuel specifications Combustion control
Carolina Power & Light	1907 MMBTU	Natural gas	2.8 lb/hr (7 lb/hr oil)	Combustion control
Casco Ray Energy Company	170 MW	Natural gas	1 PPM	Unknown
Chehalis Generating Facility	230 MW	Natural gas	7 lb/hr	Fuel specification

[a] See Table 6.1-13 for location.

Combustion Modifications

The most practical approach for reducing CO and VOC emissions is maximizing the efficiency of fuel combustion by proper design, installation, operation, and maintenance of the turbine combustor. Efficient combustion reduces the amount of fuel required to generate a given amount of power, thereby decreasing the generation of CO and VOC.

Steam/water injection for NO_x emission control increases the generation of CO emissions. Using the dry low-NO_x combustors will help decrease the formation of CO at base load.

Post-Combustion Controls

CO and VOC generated during combustion can be reacted with excess oxygen in the exhaust gas (oxidized), forming CO_2 and H_2O. There are two general post-combustion control methods: thermal oxidation and catalytic combustion. Thermal oxidation uses a flame to incinerate the pollutants. Catalytic combustion uses a catalyst to effect oxidation at the lower temperatures of the exhaust gases. In addition to oxidation, organic containments can be removed from gas streams using adsorption, condensation, or absorption technologies. However, these technologies are suited for gas streams containing much larger concentrations of hydrocarbons than found in CTG exhaust streams.

Thermal Oxidation: Thermal oxidation, also called direct-flame or direct-fired afterburners, uses an afterburner to combust the CO and VOC in the exhaust gas. Since the exhaust gas from CTGs fueled by natural gas or distillate streams contains insufficient VOCs to sustain incineration, supplemental fuel is required in the afterburner. The gas is passed through the combustion zone of the flame at a typical temperature range of 1000 to 1500 degrees F. As with other combustion systems, thermal oxidation combustors must be designed to provide sufficient residence times at high temperatures with adequate turbulence for efficient combustion. The high combustion temperatures used in the thermal incineration process produces more NO_x emissions than with catalytic incineration. Thermal oxidation units are usually located prior to heat recovery process equipment to recover some of the energy released by the supplementary fuel. Organic contaminant removal efficiencies in excess of 95 percent can be achieved; however, emissions of CO_2 and NO_x increase. Although capital costs are relatively low, supplementary fuel costs drive operating costs up.

Catalytic Oxidation: Catalytic oxidation also uses heat to oxidize CO and VOCs. This approach promotes the oxidation of CO and CO_2 without the use of reagents. Effective CO conversion occurs in the range of 700 to 1200 degrees F. The temperature of combustion turbine exhaust gas is sufficient for catalytic oxidation without requiring supplemental fuel. The reduced residence time required for catalytic incineration eliminates the need for an afterburner combustion chamber, and a flame is not generated since the gas temperatures are below the auto-ignition temperature. However, the catalyst will glow at the sites of the exothermic reaction. Other forms of catalysts such as metal mesh or pellets are available but are not as effective as the monolithic form and introduce high pressure drops to the exhaust duct system. For combustion turbines with a heat recovery steam generator unit the exhaust gas is at the highest practical temperature.

Capital costs are about 40 percent higher than those of thermal oxidation, while operating costs are lower since supplementary fuel is not required. Catalysts generally require regeneration or cleaning every 3 to 6 years. However, commercial experience with oxidation catalysts installed on gas-fired CTs reveals that catalyst cleaning or regeneration is seldom required. Since oxidation occurs on the catalyst sites, fouling of the sites by sulfur combustion products or significant amounts of particulates will reduce the catalyst removal efficiency. For this reason, the combustion of fuel oil containing more than minimal amounts of sulfur must be limited.

Carbon Adsorption: Carbon adsorption is a process by which organics are captured on the surface of granular solids. Common adsorbents include activated carbon, silica gel, and alumina. Adsorbents can be regenerated in place using steam or hot air, producing a secondary waste stream. The adsorption process is not effective, however, at temperatures below 100 degrees F, and high concentrations of volatile organic compounds (>1000 ppm) are required to achieve removal efficiencies on the order of 95 percent.

Condensation: Condensation is another technology used to separate and remove organic contaminants from gas streams. This process involves bringing the temperature of the gas stream to below the saturation temperature of the contaminants, allowing the organics to condense, and collecting the liquid phase. Like the adsorption process, condensation is only effective for gases with high concentrations of organics, capable of achieving 95 percent removal for concentrations above 5,000 ppm. This process is used primarily for product recovery in chemical process lines.

Absorption: Absorption is another removal technology developed for gas streams containing high concentrations of organics (>500 ppm). Water or organic liquids serve as the liquid absorbent used in packed towers, spray chambers, or venturi scrubbers. The gradient between the actual and the equilibrium concentration of the organics in the absorbent drives the migration of the organics in the gas stream to the absorbent liquid, and is typically enhanced at lower temperatures. The saturated liquid becomes a secondary waste stream.

Evaluation of Technical Feasibility

Both thermal and catalytic oxidation are considered technically feasible for the removal of CO and VOCs from the exhaust gas stream of a combustion turbine. The expected concentrations of organic compounds are too low for adsorption, condensation, or absorption to be considered technically feasible.

Control Technology Hierarchy

Both thermal and catalytic oxidation are considered technically feasible for the control of CO and VOCs emitted from a combustion turbine. Both technologies can achieve over 95 percent total organic contaminant removal efficiencies given optimum inlet concentrations, oxidation temperatures, and combustor or catalytic design. Catalysts are susceptible to poisoning or fouling by certain compounds in the exhaust gas which will reduce control efficiency. Sulfur compounds have been the most troublesome in the combustion of some fuel oils, solid fuels, and sewer gas. However the combustion products from burning clean fuels such as natural gas or low-sulfur No. 2 distillate (sulfur concentrations 0.05 percent by weight) do not affect the performance of an oxidation catalyst. Using an oxidation catalyst, 80 to 90 percent removal efficiencies can be achieved for CO removal from the exhaust gas combustion turbines, and 30 to 80 percent for VOCs emitted from a combustion turbine. Catalyst vendors normally do not guarantee VOC removal rates. Specific hydrocarbon destruction efficiencies are unique to each installation as they are influenced by temperature, concentration, and exhaust gas composition; however, destruction efficiencies of 80 to 90 percent can be achieved for benzene and formaldehyde in gas turbine installations.

Comparable destruction efficiencies can be obtained using thermal oxidation, although there are environmental and economic disadvantages to thermal incineration. Because the VOC concentration in turbine exhaust gas is too low to sustain combustion, supplemental fuel must be supplied, which increases costs and produces additional combustion products, including CO_2 and NO_x. In comparison to catalytic oxidation, thermal oxidation produces higher NO_x emissions as a combustion product since the oxidation (flame) temperature is much higher. Because of these environmental impacts, catalytic oxidation is ranked as the more effective technology.

BACT Analysis

The highest ranking control technology for CO and VOCs is catalytic oxidation. Because the conversion efficiency is tied directly to residence time, it can be increased by adding more catalyst material. Limitations to destruction efficiencies, therefore, become integral with the design of the exhaust system including space limitations. Economics ultimately limit the volume of catalytic material for a given project.

Environmental Impacts

Environmental impacts of using catalytic oxidation involve the disposal of the catalyst and additional products of combustion. The catalyst used to control CO in a gas turbine installation can become masked by compounds in the exhaust gas and may require thermal or chemical cleaning to expose the clogged reaction sites. Catalyst cleaning or regeneration, instead of disposal and replacement, minimizes waste associated with declining performance. As with other combustion processes, NO and other compounds containing nitrogen are converted to NO_x during catalytic oxidation. However, this is minimized by catalytic oxidation since oxidation occurs at low temperatures. Because the SCR process injects ammonia into the exhaust stream, the oxidation catalyst is typically located upstream of the SCR unit to avoid unnecessary NO_x generation. In addition, the use of oxidation catalysts results in excessive H_2SO_4 mist emissions if applied to CTs fired with fuel oil. H_2SO_4 mist emissions increase particulate emissions. An increase in H_2SO_4 emissions will also occur, on a smaller scale, from CTs fired with natural gas. In summary, there are only minor environmental impacts associated with catalytic oxidation.

Energy Impacts

The application of oxidation catalyst technology to a gas turbine will result in an increase in backpressure on the CT due to pressure drop across the catalyst bed. The increase backpressure will, in turn, constrain turbine output power, thereby increasing the unit's heat rate.

Economic Impacts

The Satsop CT Project will use natural gas as the primary fuel and distillate fuel oil will be used as a back-up fuel. Use of the oxidation catalyst technology will be feasible for natural gas-fired units. At 100 percent CT load, CO emissions for natural gas operation will be 10 ppmvd upstream of the oxidation catalyst and 2 ppmvd after the oxidation catalyst. An economic evaluation of an oxidation catalyst system was performed based on maximum CO emissions from the use of natural gas fuel. Maximum CO emissions for the Satsop CT Project occur at 60 percent CT load. The baseline emission level for CO at 60 percent CT load for natural gas operation is 125 ppmvd at an emission rate of 324 pounds per hour. CO catalyst technology is assumed to achieve CO concentrations of 25 ppmvd at 60 percent CT load, and an emission rate of 64.7 pounds per hour for natural gas operation. The cost impact analysis was conducted using the OAQPS factors summarized in Table 6.1-24 and calculations are provided in Table 6.1-25.

Base load CO emissions at 60 percent CT load are estimated to be 125 ppmvd, resulting in a controlled CO exhaust concentration of 25 ppmvd. (Controlled CO exhaust emissions at 100 percent CT load on natural gas will be 2 ppmvd.) Table 6.1-26 presents the control efficiencies for catalytic oxidation.

Cost effectiveness of the oxidation catalyst for CO emissions is determined to be $961 per ton of CO removed for each unit of the project based on 1994 dollars. Table 6.1-27 presents the proposed BACT technology and emission limits for CO and VOCs.

TABLE 6.1-24
CO CATALYST ECONOMIC COST FACTORS[a]
(PER UNIT)

Factor	Units	Value
Hours Burning Natural Gas	hours	8400
Turbine Output	MW	227
Interest Rate[b]	percent	7
Control System Life	years	10
Control System Life Capital Recovery Factor	-	0.1424
Catalyst Life	years	4
Catalyst Capital Recovery Factor	-	0.2952
Catalyst Disposal Cost	$/cu. ft.	21
Catalyst Volume	cu. ft.	16,902
Electricity Cost	$/kwh	0.084
System Downtime	hours/year	760
Labor Cost Operator/Maintenance	$/hour	36.02/43.90

[a] Based on natural gas fuel operation.
[b] Interest rate from EPA's OAQPS Cost Control Manual, 5th Edition (1996).

TABLE 6.1-25
PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS
FOR OXIDATION CATALYST[a]

Cost Type	Calculation[a]	Cost ($)
Direct Costs		
Purchased Equipment Cost		
Basic Equipment Cost = A	A	$650,000
Instrumentation	0.10 x A	$65,000
Sales Tax	0.03 x A	$19,500
Freight	0.05 x A	$32,500
Catalyst Cost	Provided	$800,000
Total Purchased Equipment Cost = B	B	$1,567,000
Direct Installation Cost		
Foundation and Support	0.12 x B	$188,040
Handling and Erection	0.40 x B	$626,800
Electrical	0.01 x B	$15,670
Piping	0.03 x B	$470,100
Insulation	0.01 x B	$15,670
Painting	0.01 x B	$15,670
Total Direct Installation Cost	0.85 x B	$1,331,950
Indirect Cost (Installation)		
Engineering	0.10 x B	$156,700
Construction and Field Expenses	0.10 x B	$156,700
Contractor Fees	0.10 x B	$156,700
Start-up	0.01 x B	$15,670
Performance Test	0.01 x B	$15,670
Contingencies	0.03 x B	$47,010
Total Indirect Costs	0.35 x B	$548,450
Total Capital Costs = C	C	**$3,447,400**
Total Annualized Capital Investment		**$267,769**

TABLE 6.1-25 (CONTINUED)
PROCEDURES FOR ESTIMATING CAPITAL AND ANNUAL COSTS FOR OXIDATION CATALYST[(a)]

Cost Type	Calculation[(a)]	Cost ($)
Direct annual costs, $/yr		
Operating labor	(0.5 hr/8 hr-shift) x ($36.02/hr) x (H)	$18,911
Supervisory labor	(0.15) x (operating labor)	$2,837
Maintenance labor and materials	2 x (0.5 hr/8-hr shift x H x $43.90/hr)	$46,095
Catalyst replacement	Provided by Vendor	$236,160
Catalyst disposal	(V) x ($21/ft^3) x (.2439)	$104,779
Total direct annual costs		$408,781
Indirect annual costs, $/yr		
Overhead	(0.6) x (all labor and maintenance material costs)	$40,705
Property taxes, insurance, and administration	(0.04) x (total capital investment)	$137,896
Capital recovery	(0.1424) x [total capital investment - (catalyst replacement/0.2952]	$457,281
Total indirect annual costs, $/yr		$635,882
Total Annual Cost		**$1,044,663**
Pollutant Controlled (tons/yr)		**1087**
Cost Effectiveness, ($/ton)		**$961**

(a) Cost factors are from EPA OAQPS Cost Control Manual, 5th Edition (1996).

TABLE 6.1-26
OXIDATION CATALYST FOR CO REMOVAL EFFICIENCY
(Per Unit)

Option	Uncontrolled Emissions	Oxidation Catalyst
(60% load)		
CO ppmvd @ 15% O_2	125	25
CO emitted (lb/hr)	323.5	64.7
CO removed (lb/hr)	Base	258.8
CO removed (tons/yr)	Base	1,087
(100% Load)		
CO ppmvd @ 15% O_2	25	2
CO emitted (lb/hr)	90	7.2
CO removed (lb/hr)	Base	82.8
CO removed (tons/yr)	Base	347.7

TABLE 6.1-27

PROPOSED BACT CO AND VOC EMISSION LIMITS FOR TWO UNITS[(a)]

Pollutant	Natural Gas						Distillate Fuel Oil		
	Emissions in ppmvd[(c)]		Emissions in lb/million BTU[(d)]		Emissions in lb/hr		100% CT Load (ppmvd)	100% CT Load (lb/million BTU)[(d)]	100% CT Load (lb/hr)
	100% CT Load	60% CT Load	100% CT Load	60% CT Load	100% CT Load	60% CT Load			
CO	2	25	0.004	0.0528	14.4	129.6	18	0.033	128
VOC[(e)]	4	7	0.004	0.008	16.2	20.8	7	0.021	28.4

(a) Emissions and stack exit parameters provided by Westinghouse.
(b) CO catalyst economic analysis based on 60 percent CT load for natural gas firing.
(c) ppmvd = parts per million volume, dry.[(d)] lb/million BTU based on fuel higher heating value.
(e) VOC emissions consider no reduction due to oxidation catalyst.

6.1.1.6 Particulate Matter

Particulate matter emissions arise primarily from non-combustible metals present in trace quantities in liquid fuels. Other sources of particulate matter include condensable unburned organics and particles in the combustion air and ammonium bisulfate and ammonium sulfate compounds from the SCR/CO catalyst. These are included in PM_{10}/TSP emission estimates.

Available Control Technologies

This section describes control technologies available for the control of particulate matter emissions and their technical feasibility specific to a gas combustion turbine. Table 6.1-28 presents the results of the RACT/BACT/LAER search for particulate matter control technologies for projects similar to the proposed Satsop CT Project. Control methods can be grouped into two categories: (1) precombustion and combustion controls, and (2) post combustion controls. As described below, pre-combustion and combustion controls include the use of clean-burning fuels and post-combustion controls include electrostatic precipitators and fabric filters.

TABLE 6.1-28
RACT/BACT/LAER SEARCH RESULTS FOR PARTICULATE MATTER

Facility[a]	Size (each turbine)	Fuel	Allowable PM Emissions	Type of Control
Carolina Power & Light	1520 MMBTU	Fuel oil	22 lb/hr	Good combustion
Chehalis Generating Facility	230 MW	Natural gas	379 lb/day	Good combustion
LSP-Cottage Grove	1988 MMBTU	Natural gas	0.0089 lb/MMBTU	Low-sulfur oil/combustion controls
Pilgrim Energy Center	1400 MMBTU	Natural gas	0.007 lb/MMBTU	Low-sulfur oil/combustion controls

[a] See Table 6.1-13 for locations.

Clean Fuels and Combustion Control

The use of clean burning fuels such as natural gas and low-sulfur No. 2 distillate oil fuel limits the presence of non-combustible metals in the fuel, thus fewer particulates are formed during combustion. Efficient combustion maintained by controlling (1) the air/fuel ratio and combustor staging sequences, and (2) the ambient conditions of the inlet air and plant loading requirements, ensure the minimum amount of condensable unburned organics are emitted. Combustion controls enable the combustion gas turbines to minimize fuel consumption as well, which in turn minimizes particulate emissions.

Post-Combustion Controls

Electrostatic precipitators and fabric filters are used on solid fuel boilers and incinerators to remove large quantities of particulate matter and ash from the flue gas of solid fuel combustion. Electrostatic precipitators use a high voltage direct current corona to electrically charge particles in the gas stream. The suspended particles are attracted to collecting electrodes of opposite polarity. These electrodes are typically plates suspended parallel with the gas flow. Particles are collected and disposed of by mechanically rapping the electrodes and dislodging the particles into the hoppers below.

Baghouses are used to collect particulate matter by drawing the exhaust gases through a fabric filter. Particulates collect on the outside of filter bags which are periodically shaken to release the particulates into hoppers.

Both technologies impose a significant pressure drop through the exhaust gas stream, requiring fans to blow the hot gases through the particulate control device and out the stack. Because particulate emissions from gas turbines are below the BACT control levels achievable using fabric filters and electrostatic precipitators (0.01 grains per standard cubic foot [gr/scf]), particulate control equipment has not been proposed for the back end of a combustion gas turbine.

Control Technology Hierarchy

The use of clean fuels and combustion control are technically feasible for particulate emissions from combustion gas turbines. When combined, both of these controls are expected to limit the emissions of particulate matter to less than 0.001 gr/scf for natural gas firing, and less than 0.008 gr/scf for low-sulfur distillate fuel oil. Particulate emissions from the primary operating fuel (natural gas) are an order of magnitude less than the levels of particulate control possible using control technologies such as electrostatic precipitators and fabric filters (0.01 gr/dsf) which typically are considered as BACT. The combination of clean burning fuels with combustion control is considered the most effective particulate control technology for combustion gas turbines.

BACT Analysis

Natural gas is the least expensive fuel available for combustion gas turbines and is approximately one third the cost of low-sulfur distillate fuel on an energy basis. Since the supply of natural gas can be curtailed for various reasons, some type of backup fuel is required to maintain the power and steam supply during these periods. The annual hours of backup fuel firing is limited to establish the expected annual emission limits. Since more particulates are emitted from the combustion of low-sulfur distillate fuel, minimizing particulate emissions is achieved along with maximizing plant operating profits by operating on natural gas as much as possible and utilizing the most fuel-efficient combustion conditions.

Selected BACT

A review of the comparable gas turbine installations in the RACT/BACT/LAER Clearinghouse identifies combustion control as the only control technology required, including the use of low-sulfur fuels. The proposed particulate matter emissions for the Satsop CT Project are representative of RACT/BACT/LAER determinations. The estimated particulate emissions for the Satsop CT Project are listed in Table 6.1-29.

TABLE 6.1-29
PROPOSED BACT PM/PM_{10} EMISSION LIMITS FOR TWO CT UNITS[(a), (b)]

Pollutant	Natural Gas		Distillate Fuel Oil	
	(lb/million BTU)[(c)]	(lb/hr)	(lb/million BTU)[(c)]	(lb/hr)
PM/PM_{10} (excluding H_2SO_4)	0.004	14.6	0.0497	190.4

(a) Based on 100 percent CT load.
(b) Emissions and stack exit parameters provided by Westinghouse.
(c) lb/million BTU based on fuel higher heating unit.

6.1.1.7 Toxic Air Pollutants

Toxic air pollutants concentrations from the CT Project are presented in Section 6.1.7.8. Low concentrations of four toxic air pollutants are present in the emissions of natural gas combustion: benzene, formaldehyde, mercury, and ammonia. Distillate fuel oil combustion also generates small quantities of formaldehyde and mercury, as well as other heavy metals. Benzene and formaldehyde are organic compounds and can be controlled by the same means as CO. Mercury and other toxic metals fall into the same category as particulate matter. The temperature is low enough for mercury to be present in a solid form. The control of ammonia slip from the SCR will be accomplished with adequate mixing and proper combustion control.

Sulfuric Acid Mist, Ammonia, and Opacity

No further emission limit data is found in the RBLC for sulfuric acid mist, ammonia, or opacity; consequently, the existing limits are proposed. Table 6.1-30 lists these proposed emission limits.

TABLE 6.1-30
MISCELLANEOUS PROPOSED BACT EMISSION LIMITS FOR EACH CT UNIT[(a)]

Pollutant	Natural Gas	Distillate Fuel Oil
Sulfuric Acid Mist	1 lb/hr	37.6 lb/hr
Ammonia	10 ppmvd	10 ppmvd
Opacity	5 %	To Be Determined During Testing

[(a)] Based on 100 percent CT load.